AIR POLLUTION CONTROL
PERMIT TO CONSTRUCT

Pursuant to Chapter 23-25 of the North Dakota Century Code, and the Air Pollution Control Rules of the State of North Dakota (Article 33-15 of the North Dakota Administrative Code), and in reliance on statements and representations heretofore made by the owner designated below, a Permit to Construct is hereby issued authorizing such owner to construct and initially operate the source unit(s) at the location designated below. This Permit to Construct is subject to all applicable rules and orders now or hereafter in effect of the North Dakota Department of Health and to any conditions specified below:

I. **General Information**:

A. **Permit to Construct Number**: PTC17020

B. **Source:**

1. Name: Davis Refinery

2. Location: Sec. 1 SW¼ & Sec. 2 SE¼, T139N, R100W
37th Street
Approximately 2 miles west of Belfield
Billings County, North Dakota
Lat: 46°52'45" N Long: 103°14'55" W

3. Source Type: Petroleum Refinery with a rated capacity of up to approximately 55,000 barrels of crude oil per day. The plant will produce refined products including gasoline, diesel fuel, jet fuel, as well as liquefied petroleum gas.

4. The construction of the Davis Refinery is scheduled to take place in two separate phases. This permit includes the emissions sources and limits from both project phases to ensure the facility will remain a minor source during both phases of operation.

5. Equipment at the Facility:

Process Unit	**Description**	**Unit (EU)**	**Point (EP)**	**Equipment or Design Features**	**e**
Unit (ADU) Crude desalting and distillation unit with an estimated capacity of 2 x 27,500 bbl/day (55,000 bbl/day total)	equipment			and Repair (ELDAR) Program Vapor Recovery Unit (VRU) system, excess emissions to flare (EU10), Design Requirements of New Source Performance Standards, Subpart NNN (NSPS NNN)	

	rated at 82.13 MMbtu/hr			(BCP), Ultra Low-NO_X Burner (ULNB), and Selective Catalytic Reduction (SCR)	
	rated at 82.13 MMbtu/hr				
				New Source Performance Standards, Subpart QQQ (NSPS QQQ)	
(VDU) ADU tower bottoms distillation unit with an estimated capacity of 16,800 bbl/day	equipment			NSPS NNN	
	at 75.00 MMbtu/hr				
(NHT) with an estimated capacity of 18,205 bbl/day	equipment			NSPS NNN	
	at 8.60 MMbtu/hr				
	Reboiler rated at 9.30 MMbtu/hr				
	rated at 17.90 MMbtu/hr				
(CRU) with an estimated capacity of 16,128 bbl/day Hydrogen (H_2) production from CRU is between 4-19 MMscf/day	equipment			NSPS NNN	
	rated at 45.63 MMbtu/hr				
	rated at 45.63 MMbtu/hr				
	rated at 45.63 MMbtu/hr				
	Reboiler rated at 5.70 MMbtu/hr				
Unit (DHT) with an estimated capacity of 19,850 bbl/day	equipment			NSPS NNN	
	at 19.50 MMbtu/hr				
	rated at 27.30 MMbtu/hr				

Hydrocracker Unit (HYK) with an estimated capacity of 14,380 bbl/day	equipment			NSPS NNN	
	rated at 37.16 MMtbu/hr				
	Heater rated at 40.34 MMbtu/hr				
(SRU) with an estimated capacity of 11.5 tpd sulfur production	equipment				
	a rated capacity of 1.58 MMbtu/hr				
	Steam Boiler #1 rated at 11.68 MMbtu/hr				
	Steam Boiler #2 rated at 11.68 MMbtu/hr				
	Steam Boiler #3 rated at 11.68 MMbtu/hr				
	Steam Boiler #4 rated at 11.68 MMbtu/hr				
	Boiler #1 rated at 22.00 MMbtu/hr				
	Boiler #2 rated at 22.00 MMbtu/hr				
	Boiler #3 rated at 22.00 MMbtu/hr				
	(HC) operating flare rated to handle up to 24.4 MMscf/day (including purge and fuel gas blowdown)			Smokeless Operation	
	handle up to 15.8 MMscf/day			Smokeless Operation	
	rated to handle up to 74.6 MMscf/day			Smokeless Operation	

	rated to handle up to 88.8 MMscf/day			Smokeless Operation	
	VRU system			MACT BBBBBB (6B)	
Plant (WWTP)	from Benzene Waste Operators NESHAP (BWON) compliant plant			NESHAP FF	
five cell induced draft counter flow system with a water circulation rate of 2,500 gal/min for each cell.				maximum drift) inherent to design	
	Power Generators each rated at 4,700 BHP	14B 14C	14B 14C		
	Engine Firewater Pumps each rated at 600 BHP	15B 15C	15B 15C		

[A] Common flue stack.

[B] Merichem LO-CAT® technology, reduction control.

[C] Common flue stack. Under normal operations, during Phase 1, two will be in service and one on stand-by, during Phase 2, three will be in service and one on stand-by.

[D] Under normal operations, two will be in service and one on stand-by.

[E] Under normal operations, the acid gas flow is routed to the SRU.

[F] Under normal operations, during Phase 1, one will be in service and one on stand-by. During Phase 2, four will be in service and one on stand-by.

[G] The engines shall be certified to emissions standards as outlined under 40 CFR 60, Subpart IIII. The engines shall be manufactured and installed with the appropriate control equipment to meet these emissions standards.

6. Storage Tanks:

Storage Area		**(bbl)**		
				(IFR), Submerged Fill Pipe (SFP)
Products			naphtha	
			and Diesel)	

			Oil	
			naphtha	
			naphtha	
			(ULSD)	

A Insignificant emissions units.

C. **Owner/Operator (Permit Applicant)**:

1. Name: Meridian Energy Group, Inc.
2. Address: 37th Street
   Belfield, ND 58622
3. Application Date: October 6, 2016 (original)
   April 5, 2017 (amendment)
   June 27, 2017 (supplemental information)

II. **Conditions**: This Permit to Construct allows the construction and initial operation of the above-mentioned new or modified equipment at the source. The source may be operated under this Permit to Construct until a Permit to Operate is issued unless this permit is suspended or revoked. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Health and to the conditions specified below.

A. **Emission Limits**: Emission limits from the operation of the source unit(s) identified in Item I.B of this Permit to Construct (hereafter referred to as "permit") are as follows. Source units not listed are subject to the applicable emission limits specified in the North Dakota Air Pollution Control Rules.

Emission Unit	**EU**	**EP**	**Pollutant/ Parameter**	**Emission Limit or Design / Work Practice**	**Reference Condition II.A**

ADU process equipment				ELDAR NSPS NNN	10 16
ADU Feed Heater #1 rated heat input of 82.13 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0063 lb/MMbtu (6 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.a 5.b 4.a 6 7
ADU Feed Heater #2 rated heat input of 82.13 MMbtu/hr			CO (Phase 2) H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0063 lb/MMbtu (6 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.a 5.b 4.a 6 7
ADU sewers			VOC	NSPS QQQ	11
VDU process equipment				ELDAR NSPS NNN	10 16
VDU Feed Heater rated at 75.00 MMbtu/hr			CO (Phase 2) H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0063 lb/MMbtu (6 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.a 5.b 4.a 6 7
VDU sewers				NSPS QQQ	11
NHT process equipment				ELDAR NSPS NNN	10 16

NHT Feed Heater rated 8.60 MMbtu/hr			 CO (Phase 1) CO (Phase 2) H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0300 lb/MMbtu (29 ppmvd @ 0% O_2) 0.0380 lb/MMbtu (60 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.b 5.a 5.b 4.a 6 7
NHT Stabilizer Reboiler rated 9.30 MMbtu/hr			 CO (Phase 1) CO (Phase 2) H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0300 lb/MMbtu (29 ppmvd @ 0% O_2) 0.0380 lb/MMbtu (60 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.b 5.a 5.b 4.a 6 7
NHT Splitter Reboiler rated at 17.90 MMbtu/hr			 CO (Phase 1) CO (Phase 2) H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0300 lb/MMbtu (29 ppmvd @ 0% O_2) 0.0380 lb/MMbtu (60 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.b 5.a 5.b 4.a 6 7
NHT sewers				NSPS QQQ	11
CRU process equipment				ELDAR	10

CRU Reactor #1 Heater rated at 45.63 MMbtu/hr) CRU Reactor #2 Heater rated at 45.63 MMbtu/hr CRU Reactor #3 Heater rated at 45.63 MMbtu/hr			CO (Phase 1) CO (Phase 2) H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0063 lb/MMbtu (6 ppmvd @ 0% O_2) 0.0380 lb/MMbtu (60 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.a 5.a 5.b 4.a 6 7
CRU Stabilizer Reboiler rated at 5.70 MMbtu/hr			CO (Phase 1) CO (Phase 2) H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0300 lb/MMbtu (29 ppmvd @ 0% O_2) 0.0380 lb/MMbtu (60 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.b 5.a 5.b 4.a 6 7
CRU Regenerator Vent				20%	Condition II.E.10
CRU sewers				NSPS QQQ	11
DHT process equipment				ELDAR NSPS NNN	10 16

DHT Feed Heater rated at 19.50 MMbtu/hr			CO (Phase 1) CO (Phase 2) H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0300 lb/MMbtu (29 ppmvd @ 0% O_2) 0.0380 lb/MMbtu (60 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.b 5.a 5.b 4.a 6 7
DHT Splitter Reboiler rated at 27.30 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0300 lb/MMbtu (29 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.b 5.b 4.a 6 7
DHT sewers				NSPS QQQ	11
HYK process equipment				ELDAR NSPS NNN	10 16
HYK Reactor Heater rated at 37.16 MMtbu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0063 lb/MMbtu (6 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.a 5.b 4.a 6 7

HYK Fractionator Heater rated at 40.34 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0063 lb/MMbtu (6 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.a 5.b 4.a 6 7
HYK sewers				NSPS QQQ	11
SRU process equipment				ELDAR	10
Thermal Oxidizer with a rated capacity of 1.58 MMbtu/hr			Opacity	2,500 ppm SO_2 5%	8 7
SRU sewers				NSPS QQQ	11
Process equipment				ELDAR	10
Medium Pressure Steam Boiler #1 rated at 11.68 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0300 lb/MMbtu (29 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) Pipeline Quality Natural Gas 0.0040 lb/MMbtu 5%	3.b 5.b 4.b, 17 6 7
Medium Pressure Steam Boiler #2 rated at 11.68 MMbtu/hr					
Medium Pressure Steam Boiler #3 rated at 11.68 MMbtu/hr					
Medium Pressure Steam Boiler #4 rated at 11.68 MMbtu/hr					
High Pressure Steam Boiler #1 rated at 22.00 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0300 lb/MMbtu (29 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.b 5.b 4.a, 17 6 7

High Pressure Steam Boiler #2 rated at 22.00 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0300 lb/MMbtu (29 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.b 5.b 4.a, 17 6 7
High Pressure Steam Boiler #3 rated at 22.00 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	0.0300 lb/MMbtu (29 ppmvd @ 0% O_2) 0.0280 lb/MMbtu (44 ppmvd @ 0% O_2) 15 ppmv H_2S in fuel gas [A] 0.0040 lb/MMbtu 5%	3.b 5.b 4.a, 17 6 7
Process equipment				ELDAR	10
Storage Tank Farm				MACT WW	12.a
				MACT WW	12.a
				MACT WW	12.a
				NSPS Kb	12.b
				MACT WW	12.a
				MACT WW	12.a
				NSPS Kb	12.b
				MACT 6B via MACT WW	12.a
				MACT 6B via MACT WW	12.a
				MACT 6B via MACT WW	12.a
				MACT 6B via MACT WW	12.a
				MACT 6B via MACT WW	12.a
				MACT 6B via MACT WW	12.a
				MACT WW	12.a
				MACT WW	12.a
				NSPS Kb	12.b
				NSPS Kb	12.b
				NSPS Kb	12.b

Oil Movements				NSPS QQQ	11
Enclosed hydrocarbon (HC) operating flare rated to handle up to 24.4 MMscf/day (including purge and fuel gas blowdown)			Opacity	NSPS Ja – flare header connected to VRU 0%	9 9.f
Acid gas flare rated to handle up to 15.8 MMscf/day			H_2S/TRS Opacity	Routed to SRU under normal operations, NSPS Ja – flare header 0%	9 9.d 9.f
HC secondary flare #1 rated to handle up to 74.6 MMscf/day of emergency relief			Opacity	NSPS Ja – secondary flare with water seal 0%	9, 9.c 9.f
HC secondary flare #2 rated to handle up to 88.8 MMscf/day of emergency relief			Opacity	NSPS Ja – secondary flare with water seal 0%	9, 9.c 9.f
Process Equipment				ELDAR	10
Truck loading rack				ELDAR MACT Subpart 6B	10 13
Oil/Separator inlet from Benzene Waste Operators NESHAP (BWON) compliant plant			Total Annual Benzene (TAB)	NSPS QQQ NESHAP FF	11 14
CT cell #1			Compounds	NESHAP Q	15
CT cell #2					
CT cell #3					
CT cell #4					
CT cell #5					
Three Diesel Engine Power Generators each rated at 4700 BHP	14B 14C	14B 14C	PM Opacity	4.8 g/bhp-hr 0.15 g/bhp-hr 20%	18.a.i 18.a.ii 18.a.iii
Three Back-up Diesel Engine Firewater Pumps each rated at 600 BHP	15B 15C	15B 15C	PM	3.0 g/bhp-hr 0.15 g/bhp-hr	18.b.i 18.b.ii

Total Volatile Organic Compounds (VOC) from EUs: 1, 1A, 1B, 1C, 2, 2A, 2B, 3, 3A, 3B, 3C, 3D, 4, 4A, 4B, 4C, 4D, 4F, 5, 5A, 5B, 5C, 6, 6A, 6B, 6C, 7, 8, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 9, 9A, 9B, 10, 10A, 10B, 10C, 11, 11A, 12, 13, 14A-C, 15A-C		58 tons/year (12-month rolling sum) [B]	Condition II.D.1
Total Carbon Monoxide (CO) from EUs: 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C		80 tons/year (12-month rolling sum) [B]	Condition II.D.2
Total Nitrogen Oxides (NO_X) from EUs: 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C		40 tons/year (12-month rolling sum) [B]	Condition II.D.3
Total Sulfur Dioxide (SO_2) from EUs: 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C	(RFG H_2S content used for SO_2 from combustion)	13 tons/year (12-month rolling sum) [B]	Condition II.D.4

[A] The permittee shall monitor H_2S at a single point using a continuous monitor system (CMS) located at the fuel gas distribution header.

[B] The emission limit applies to the combined emissions from all listed emission units.

1. **Best Management Practices**:

At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

2. **40 CFR 60, Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007**

All fuel gas combustion devices (FGCD), flares, and the sulfur recovery unit at the facility are subject to the design, equipment, and work practice or operational standards of new source performance standards (NSPS) Subpart Ja, specifically, 40 CFR (§)60.103a.

Root Cause Analysis and Corrective Action Analysis: Each FGCD, flare, and sulfur recovery plant shall conduct a root cause analysis and corrective action analysis for each of the conditions specified in §60.103a(c)(1) through (c)(3). The root cause analysis and corrective action analysis must be completed by the schedule provided in §60.103a(d) and shall implement the corrective actions in accordance with §60.103a(e).

3. **FGCD Nitrogen Oxide (NO_X) Emissions**:

The permittee has elected to comply with NO_X emission limits which are more stringent then NSPS Ja. The following emissions limits are applicable to the FGCD, based on the control technology:

a. Ultra-Low NO_X Burners (ULNB) with Selective Catalytic Reduction (SCR): For EUs 1A, 1B, 2A, 4A, 4B, 4C, 6A, and 6B. The permittee shall not discharge or cause the discharge of any gases into the atmosphere that contain NO_X in excess of 0.0063 lb/MMbtu determined daily on a 30-day rolling average basis (equivalent to no greater than 6 ppmvd, corrected to 0% excess O_2).

b. ULNB: For EUs 3A, 3B, 3C, 4D, 5A, 5B, 8A, 8B, 8C, 8D, 8E, 8F, and 8G. The permittee shall not discharge or cause the discharge of any gases into the atmosphere that contain NO_X in excess of 0.0300 lb/MMbtu determined daily on a 30-day rolling average basis (equivalent to no greater than 29 ppmvd, corrected to 0% excess O_2).

4. **Fuel Gas Combustion Sulfur Dioxide (SO_2) Emissions**:

The permittee has elected to comply with SO_2 emission limits which are more stringent than NSPS Ja. The permittee shall use a continuous monitor system (CMS) to monitor the H_2S concentration from the refinery fuel gas (RFG) system to determine SO_2 emissions from each FGCD which burns RFG. The permittee has elected to install the CMS on the RFG system header exiting the SRU that is common to all the FGC units to comply with §60.102a(2)(i). The following limits apply, based on the fuel burned:

a. The process heaters and high pressure boilers (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8E, 8F, and 8G) shall not burn refinery fuel gas that contains H_2S in excess of 15 ppmv determined daily on a 30-day rolling average basis.

b. The Medium Pressure Boilers (EUs 8A, 8B, 8C, and 8D) and Flare System (EU 10, 10A, 10B,and 10C) pilots shall be fired on pipeline quality natural gas containing no more than 2 grains of H_2S per 100 standard cubic feet.

5. **Fuel Gas Combustion Carbon Monoxide (CO) Emissions**:

Best Combustion Practices (BCP) for all process heaters and boilers (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, and 8G). The permittee shall comply with the following limits:

a. During Phase 1, shall not discharge or cause the discharge of any gases into the atmosphere that contain CO in excess of 0.0380 lb/MMbtu determined daily on a

30-day rolling average basis (equivalent to no greater than 60 ppmvd, corrected to excess O_2).

b. During Phase 2, shall not discharge or cause the discharge of any gases into the atmosphere that contain CO in excess of 0.0280 lb/MMbtu determined daily on a 30-day rolling average basis (equivalent to no greater than 44 ppmvd, corrected to 0% excess O_2).

6. **Fuel Gas Combustion Particulate Matter <10 microns (PM_{10}) and PM <2.5 microns ($PM_{2.5}$) Emissions**:

Combined filterable and condensable fractions. For all process heaters and boilers (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, and 8G), the permittee shall not discharge or cause the discharge of any gases into the atmosphere that contain PM_{10} and/or $PM_{2.5}$ in excess of 0.0040 lb/MMbtu calculated as the average of three valid 1-hour test runs.

7. **Fuel Gas Combustion Opacity:**

For all process heaters and boilers (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, and 8G), the permittee shall comply with the opacity limit of 5% except for one six-minute period per hour when 10% opacity is permissible.

8. **Sulfur Recovery Unit (SRU) SO_2 Emissions**:

The SRU (EU 7) is classified as a sulfur recovery plant with a capacity of less than 20 long tons per day with a reduction control system followed by incineration. Thermal Oxidizer (EU 7A; EP 7A) is the incinerator following the SRU and is the only point source of emissions in the process area.

The permittee shall not discharge or cause the discharge of any gases into the atmosphere in excess of 2,500 ppm by volume of SO_2 (dry basis) at zero percent excess air, on a 12-hour rolling average basis to comply with §60.102a(f)(2)(i).

9. **Flare Operation**:

The permittee has elected to construct and operate the refinery with a cascaded flare system. This system will be equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction. HC Operating Flare (EU 10) will be the first flare downstream of the flare gas recovery system. HC Secondary Flare #1 (EU 10B), HC Secondary Flare #2 (EU 10C) will be secondary flares fitted with water seals downstream of EU 10. In addition, the permittee has elected to manage process upset gases released to the flare system as a result of emergency malfunctions from the sour water unit and/or sulfur recovery unit through a separate Acid Gas Flare (EU 10A).

The permittee shall comply with the following:

a. The blowdown and flare system shall be designed and operated in accordance with the requirements of North Dakota Administrative Code (NDAC) 33-15-12-02, Subpart A, 60.18 (§60.18). The flare shall be operated with a flame present at all times when emissions may be vented to the flare.

b. The flare system is subject to the H_2S limitations of §60.103a(h). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this the limit requirements of §60.103a(h).

c. The cascaded flare system, including EU 10, EU 10B and EU 10C shall comply with the emission monitoring provisions of 40 CFR 60.107a(g).

d. The acid flare EU 10A shall comply with the applicable emission monitoring provisions of §60.107a(e) and (f).

e. The permittee shall develop and implement a written flare management plan by no later than the date that the flare becomes an affected facility subject to this subpart, except for the selected minimization alternatives in §60.103a(a)(2) and/or the procedures in §60.103a(a)(5) though (a)(7) that cannot reasonably be implemented by that date, which the owner or operator must implement in accordance with the schedule in the flare management plan. The plan must include the information described in §60.103a(a)(1) through (a)(7).

f. Flare Visible Emissions: Flares shall be operated with no visible emissions except for periods not to exceed a total of five minutes during any two consecutive hours. Reference Method 22 of 40 CFR 60, Appendix A shall be used to determine compliance with this visible emissions provision.

10. **Enhanced Leak Detection & Repair (ELDAR) Program**:

The permittee is subject to 40 CFR 60, Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (NSPS GGGa). NSPS GGGa references 40 CFR 60, Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (NSPS VVa) for the standards of compliance.

As allowed under NSPS VVa[1], the permittee has elected to comply with the requirements of 40 CFR 63, Subpart H – National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks (MACT H).

For all equipment in VOC service, as defined in §60.481a, located at EUs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, and 11A, the permittee shall comply with the following standards:

a. General. The Permittee shall comply with the general standards under §63.162.

b. Pumps in light liquid service. Each pump in light liquid service shall be equipped with a duel mechanical seal that includes a barrier fluid system meeting the requirements of §63.163(e).

c. Compressors. Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of process fluid to the atmosphere and meets the requirements of §63.164(b) – (e).

d. Pressure relief devices in gas/vapor service. All pressure relief devices in gas/vapor service shall meet the requirements of §63.165(a) – (d). Pressure relief devices that are connected to the flare gas header are exempt (§63.172(b)).

e. Sampling connection systems. All sampling connection systems shall meet the requirements of §63.166(a) – (c).

f. Open-ended valves or lines. All open-ended valves and lines shall meet the requirements of §63.167(a) – (e).

g. Valves in gas/vapor service and in light liquid service. All valves in gas/vapor and light liquid service shall meet the requirements of §63.168(a) – (h).

h. Pumps, valves, connectors, and agitators in heavy liquid service; instrument systems; and pressure relief devices in liquid service. All Pumps, valves, connectors, and agitators shall meet the requirements §63.169(a) – (d).

i. Surge control vessel and bottoms receivers. Each surge control vessel and bottom receiver shall meet the requirements of §63.172(a) – (n).

j. Closed-vent systems and control devices. Each closed-vent systems and control devices shall meet the requirements of §63.172(a) – (n).

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[1] 40 CFR 60, Subpart VVa. §60.480a(e)(2)(i) "Owners or operators may choose to comply with the provisions of 40 CFR part 63, subpart H, to satisfy the requirements of §60.482-1a through §60.487a for an affected facility. When choosing to comply with 40 CFR part 63, subpart H, the requirements of §60.485a(d), (e), and (f), and §60.486a(i) and (j) still apply."

k. Agitators in gas/vapor service and in light liquid service. Each agitator in gas/vapor and light liquid service shall meet the requirements of §63.173(a) – (j).

l. Connectors in gas/vapor service and in light liquid service. Each connector in gas/vapor service and light liquid service shall meet the requirements of §63.174(a) – (j).

m. Delay of Repair. The Permittee shall comply with the delay of repair (DOR) requirements under §63.171.

The permittee shall meet emission reductions equivalent to the Texas Commission on Environmental Quality (TCEQ) 28LAER program[2].

Additionally, the permittee shall implement the ELDAR program for equipment with a screening rate of 500 parts per million by volume (ppmv), except for compressors (10,000 ppmv), summarized as follows:

Equipment/Service		TCEQ 28LAER Control Efficiency	Leak Threshold (ppmv)
Valves	Gas/Vapor	97%	500
	Light Liquid	97%	500
	Heavy Liquid	0%	500
Pumps	Light Liquid	85%	500
	Heavy Liquid	85%	500
Flanges/ Connectors	Gas/Vapor	97%	500
	Light Liquid	97%	500
	Heavy Liquid	30%	500
Compressors		85%	10,000
Relief Valves (Gas/Vapor)		97%	500
Sampling Connections		97%	500

The use of Alternative Work Practice (AWP) monitoring, such as optical gas imaging (OGI) in conjunction with approved Method 21 analyzers or other AWP as approved by the Department, shall be used to improve the efficiency of the ELDAR program. The permittee shall conduct AWP monitoring using OGI with Method 21 analyzers at least every 60 days.

11. **40 CFR 60 Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (NSPS QQQ)**

For all individual drain systems, oily water separators, and closed vent systems in the

[2] Attachment 1 <https://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/fugitives/nsr_fac_eqfug.html>

petroleum refinery wastewater system, as defined in §60.691, located at EUs 1C, 2B, 3D, 4F, 5C, 6C, 7B, 9B, and 12, the permittee shall comply with the following standards:

a. Individual Drain Systems

The individual drain systems requirements apply to the drains, junction boxes, and sewer lines which are part of the refinery process wastewater system.

i. Each drain shall be equipped with water seal controls.

ii. Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 3 feet (90 cm) in length and shall not exceed 4 inches (10.2 cm) in diameter. Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.

iii. Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

b. Oily Water Separator (OWS)

i. Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart shall be equipped and operated with a fixed roof, which meets the specifications in §60.692-3 (a), (b), (e), and (f), as applicable.

ii. Storage vessels subject to 40 CFR 60, Subpart Kb (§60.112b) are not subject to the requirements of this subpart.

iii. Oily wastewater resulting from tank draws shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system as indicated in §60.692-4(e).

c. Closed Vent System

i. Each closed vent system, vapor recovery system, and/or flare shall comply with the requirements of §60.692-5(b) – (e).

d. Exempt facilities and delay of repair

An owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the following facilities meet the exemption requirements of NSPS QQQ.

i. Stormwater sewer system, which no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.

ii. Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily water.

iii. Non-contact cooling water system, which demonstrates that the cooling water does not contact hydrocarbons or oily wastewater and is not recirculated through a cooling tower.

iv. Delay of repair of facilities that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown. Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

12. **Volatile Organic Liquids (VOL) Storage Tanks**

a. All internal floating roof tanks (IFRT) at the facility are subject to 40 CFR 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (NSPS Kb).

NSPS Kb gasoline storage tanks are subject to the storage tank requirements of 40 CFR 63, Subpart BBBBBB – National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities (MACT 6B) depending on the material stored in the tank.

As allowed[3,4] for IFR tanks, the permittee has elected to comply with the more stringent requirements of 40 CFR 63, Subpart WW – National Emission Standards for Storage Vessels (Tanks) – Control Level 2 (MACT WW) and shall comply with floating roof requirements, specifically §63.1063(a) – (b).

Applicable to tanks: 301, 302, 305, 306, 307, 308, 309, 311, 312, 327, 328, 331, and 332.

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[3] 40 CFR 63, Subpart BBBBBB. Table 1, 2.(d) "Equip and operate each internal floating roof gasoline storage tank according to the applicable requirements in §63.1063(a)(1) and (b), except for the secondary seal requirements under §63.1063(a)(1)(i)(C) and (D)"

[4] 40 CFR 63, Subpart CC. §63.640(n) "Overlap of this subpart with other regulations for storage vessels." allows sources subject to both NSPS Kb and MACT CC to comply with only one of the subparts. Subsequently, §63.660 states "the owner or operator of a Group 1 storage vessel that is part of a new or existing source shall comply with the requirements in subpart WW of this part according to the requirements in paragraphs (a) through (i) of this section"

b. The fixed roof tanks (FRT) are not subject to the design standards of NSPS Kb.

Applicable to tanks: 313, 315, 316, 324, and 325.

c. All tanks shall be equipped with and filled through a submerged fill pipe to comply with NDAC Section 33-15-07-01.3.

13. **40 CFR 63 Subpart BBBBBB – National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities (MACT 6B)**:

The truck loading rack (EU 11and 11A) is subject to MACT 6B and shall be operated with a submerged filling arm and Vapor Recovery Unit (VRU) at all times when gasoline loading operations are occurring. The permittee shall comply with the following:

a. Load gasoline only in vapor tight cargo tanks that have been tested with the frequency and by the methods specified in 40 CFR 63.425 to assure vapor tightness.

b. Product throughput records shall be submitted annually. Records shall be maintained for a minimum of three years.

c. ELDAR and/or Olfactory, Visual and Audible (OVA) observations shall be conducted at a minimum every 30-days.

d. NSPS Kb storage tanks shall comply with the conditions of MACT 6B.

14. **40 CFR 61 Subpart FF – National Emission Standard for Benzene Waste Operations (BWON)**:

The Wastewater Treatment Plant (EU 12) and individual drain lines that convey process waste water to the oily water treatment system are subject to the BWON provisions. The provisions of this subpart apply to individual drain systems used to convey process wastewater from a process unit, product storage tank, or waste management unit to a waste management unit. Individual drain systems include all process drains and common junction boxes, together with their associated sewer lines and other junction boxes, down to the receiving wastewater treatment system. Waste that is contained in a segregated stormwater sewer system and any gaseous stream from a waste management unit, treatment process, or wastewater treatment system routed to a fuel gas system, are exempt from compliance with the provisions of this subpart.

15. **Five Cell Cooling Tower**:

For the Cooling Tower (EU 13), the permittee shall comply with the following:

a. The cooling towers shall be equipped with and operated with mist eliminators that are guaranteed to limit drift to 0.001% or less of the circulating flow.

b. Per 40 CFR 63 Subpart Q, the permittee shall not use chromium based water treatment chemicals in the cooling towers.

16. **40 CFR 60 Subpart NNN – Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations (NSPS NNN)**:

The process units at the Davis Refinery associated with the generation of LPG, light naphtha and gasoline range compounds as a product, co-product, by-product, or intermediate include the ADUs (EU 1) and VDU (EU 2), NHT (EU 3), CRU (EU 4), Benzene Saturation Unit and HYK (EU 6). As such, these units are subject to Subpart NNN.

As allowed by this subpart, the permittee has chosen to install a vapor recovery system designed, sized, and operated to capture all flows discharged through the vent streams of the above mentioned units except those resulting from startup, shutdown or malfunction. To comply with the standards of §60.662, the permittee will combust in a flare the emissions in excess of the VRU capacity.

17. **40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (NSPS Dc)**:

The Medium Pressure Boilers (EUs 8A – 8D) and High Pressure Boilers (EU 8E – 8G), EUs 8A to 8G, are subject to the applicable reporting and recordkeeping requirements of NSPS Dc. The permittee has elected to run the Medium Pressure Boilers exclusively on pipeline quality natural gas, while the high pressure boilers will be run on refinery fuel gas. Permittee shall maintain records of the type and amount of fuel used by the boilers on a daily basis to comply with §60.48c(g)(1).

18. **40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (NSPS IIII)**:

a. Emergency diesel generators (EUs 14A-14C), 4,700 bhp each, are subject to the provisions of §60.4202(b)(2), which references §89.112 and §89.113, as follows:

i. NMHC (non-methane hydrocarbons) + NO_X limit: 4.8 g/bhp-hr (6.4g/kW-hr)

ii. PM limit: 0.15 g/bhp-hr (0.20 g/kW-hr)

iii. Opacity limit: 20% during acceleration, 15% during lugging, and 50% during peaks in acceleration or lugging

b. Emergency diesel fire pump engines (EUs 15A-15C), 600 bhp each, are subject to the provisions of §60.4205(c) and shall comply with the emissions standards in Table 4 to Subpart IIII, as follows:

i. NMHC + NO_X limit: 3.0 g/bhp-hr

ii. PM limit: 0.15 g/bhp-hr

B. **Emissions Testing**:

1. **Initial Testing**: Within 60 days after achieving the maximum production rate at the plant, but not later than 180 days after startup, the permittee shall conduct emissions tests following the Methodology in 40 CFR 60, Appendix A, for the contaminants listed below:

Note: FGCDs subject to both a Phase 1 and Phase 2 CO emissions limit will be required to demonstrate compliance with both limits (i.e. Phase 1 CO compliance testing after Phase 1, and Phase 2 CO compliance testing after Phase 2).

Emissions Testing

Process Unit	**EP**	**Contaminant**
ADU Feed Heater #1	1A	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
ADU Feed Heater #2	1B	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
VDU Feed Heater	2A	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
NHT Feed Heater	3A	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
NHT Stabilizer Reboiler	3B	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]

NHT Splitter Reboiler	3C	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
CRU Reactor #1/2/3 Heater	4	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
CRU Stabilizer Reboiler	4D	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
CRU Regenerator Vent	4E	Opacity [E]
DHT Feed Heater	5A	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
DHT Splitter Reboiler	5B	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
HYK Reactor Heater	6A	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
HYK Fractionator Heater	6B	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
Thermal Oxidizer	7A	SO_2
Medium Pressure Steam Boiler #1/2/3/4	8	NO_X CO SO_2 [C] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
High Pressure Steam Boiler #1	8E	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
High Pressure Steam Boiler #2	8F	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
High Pressure Steam Boiler #3	8G	NO_X CO H_2S in fuel gas [B] PM_{10} & $PM_{2.5}$ (Filterable + Condensable) [A]
Enclosed hydrocarbon (HC)	10	[D]
Acid gas flare	10A	[D]
HC secondary flare #1	10B	[D]
HC secondary flare #2	10C	[D]

Diesel Engine Power Generator	14A-C	NO_X NMHC PM
Back-up Diesel Engine Firewater Pump	15 A-C	NO_X NMHC PM

[A] Testing must follow EPA Method 201A and 202; these are not contained in 40 CFR 60, Appendix A.

[B] Testing must either be conducted to measure the SO_2 emission rate or the H_2S concentration of the fuel gas. The permittee shall comply with all applicable requirements of 40 CFR 60.104a.

[C] In lieu of 40 CFR 60 Appendix A compliance, permittee shall provide certification of pipeline quality natural gas sulfur content.

[D] Flare units are not subject to initial performance testing as they are not intended to operate on a routine basis, only in upset conditions. Flare unit compliance will be based on CEMS relative accuracy testing and certification of pipeline quality natural gas sulfur content for the operations of the pilot units.

[E] Reference Method 9 test required for initial compliance demonstration.

2. **Notification**: The permittee shall notify the Department using the form in the Emission Testing Guideline, or its equivalent, at least 30 calendar days in advance of any tests of emissions of air contaminants required by the Department. If the permittee is unable to conduct the performance test on the scheduled date, the permittee shall notify the Department at least five days prior to the scheduled test date and coordinate a new test date with the Department.

3. **Sampling Ports/Access**: Sampling ports shall be provided downstream of all emission control devices and in a flue, conduit, duct, stack or chimney arranged to conduct emissions to the ambient air.

   The ports shall be located to allow for reliable sampling and shall be adequate for test methods applicable to the facility. Safe sampling platforms and safe access to the platforms shall be provided. Plans and specifications showing the size and location of the ports, platform, and utilities shall be submitted to the Department for review and approval.

4. **Other Testing**:

   a. The Department may require the permittee to have tests conducted to determine the emission of air contaminants from any source, whenever the Department has reason to believe that an emission of a contaminant not addressed by the permit applicant is occurring, or the emission of a contaminant in excess of that allowed by this permit is occurring. The Department may specify testing methods to be used in accordance with good professional practice. The Department may observe the testing. All tests shall be conducted by reputable, qualified personnel. The Department shall be given a copy of the test results in writing and signed by the person responsible for the tests.

All tests shall be made and the results calculated in accordance with test procedures approved by the Department. All tests shall be made under the direction of persons qualified by training or experience in the field of air pollution control as approved by the Department.

b. The Department may conduct tests of emissions of air contaminants from any source. Upon request of the Department, the permittee shall provide the necessary holes in stacks of ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices, as may be necessary for proper determination of the emission of air contaminants.

C. **Stack Heights**: Emissions shall be vented through stacks that meet the following height requirements. Stack heights may be no less than those listed in the table below without prior approval from the Department.

Emission Unit Description	**Emission Point (EP)**	**Stack Height (Feet)**
ADU Feed Heater #1	1A	128
ADU Feed Heater #2	1B	128
VDU Feed Heater	2A	125
NHT Feed Heater	3A	91
NHT Stabilizer Reboiler	3B	91
NHT Splitter Reboiler	3C	105
CRU Reactor #1/2/3 Heater	4	130
CRU Stabilizer Reboiler	4D	42
CRU Regenerator Vent	4E	40
DHT Feed Heater	5A	96
DHT Splitter Reboiler	5B	91
HYK Reactor Heater	6A	100
HYK Fractionator Heater	6B	100
Thermal Oxidizer	7A	60
Medium Pressure Steam Boiler #1/2/3/4	8	100
High Pressure Steam Boiler #1	8E	100
High Pressure Steam Boiler #2	8F	100
High Pressure Steam Boiler #3	8G	100
Enclosed hydrocarbon (HC) operating flare	10	50
Acid gas flare	10A	150
HC secondary flare #1	10B	150
HC secondary flare #2	10C	150

D. **Annual Emissions Restrictions**:

1. **VOC Emissions Calculations**: By the 15th day of each month, the owner/operator shall calculate and record the total VOC emissions from the following emission units: EUs 1, 1A, 1B, 1C, 2, 2A, 2B, 3, 3A, 3B, 3C, 3D, 4, 4A, 4B, 4C, 4D, 4F, 5, 5A, 5B, 5C, 6, 6A, 6B, 6C, 7, 7A, 7B, 8, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 9, 9A, 9B, 10, 10A, 10B, 10C, 11,

11A, 12, 13, 14A-C, 15A-C for the previous month and for the previous 12 months (12-month rolling total). Emissions shall be calculated in a method as shown below.

VOC_{Total} = $VOC_{HEATERS/BOILERS}$ (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G) + $VOC_{ENGINES}$ (EUs 14A-C, 15A-C)+ VOC_{LEAKS} (EUs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 11A) + VOC_{TANKS} EU (9A) + VOC_{FLARES} (EUs 10, 10A, 10B, 10C) + VOC_{WWTP} (EU 12) + VOC_{CT} (EU 13)

Where:

$VOC_{HEATERS/BOILERS}$ = Total VOC emissions (in tons) from EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G

$VOC_{HEATERS/BOILERS}$ = (Total heat content of refinery gas combusted in 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, million Btu) x (0.0054 lb VOC / million Btu heat input) / 2000

$VOC_{ENGINES}$ = Total VOC emissions (in tons) from EUs 14A-C, 15A-C from non-emergency operations

$VOC_{ENGINES}$ = [((hours of operation of EUs 14A-C) x (7.05×10^{-4} lb of VOC / hour of operation) x (bhp of EUs 14A-C)) + ((hours of operation of EUs 15A-C) x (7.05×10^{-4} lb of VOC / hour of operation) x (bhp of EUs 15A-C))] / 2000

VOC_{LEAKS} = Total VOC emissions (in tons) from EUs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 11A

VOC_{LEAKS} = Total VOC emissions calculated via ELDAR program monitoring

VOC_{TANKS} = Total VOC emissions (in tons) from EU 9A

VOC_{TANKS} = Calculated utilizing EPA's methodology from Chapter 7 of AP-42: Liquid Storage Tanks

$VOC_{FLARING}$ = Total VOC emissions (in tons) from EUs 10, 10A, 10B, 10C

$VOC_{FLARING-PILOT}$ = (total heat content of pilot gas combusted in EU 10, 10A, 10B, and 10C, million Btu) x (0.0054 lb VOC/ million Btu heat input) / 2000

$VOC_{FLARING-BLOWDOWN}$ = (Blowdown hours) x (0.8 lb VOC / Mbbl Refining Capacity) x (Crude Processing Rate, Mbbl/day) / 24 / 2000

VOC_{WWTP} = Total VOC emissions (in tons) from EU 12

VOC_{WWTP} = (total WWTP flow, 1000 gallons) x (0.5 lb VOC / 1000 gallons of wastewater)

VOC_{CT} = Total VOC emissions (in tons) from EU 13

VOC_{CT} = [(hours of operation per CT cell) x (0.006 lb/hr)] / 2000

Combined VOC emissions from the emission units listed are restricted to 58.0 tons per year. If total calculated combined VOC emissions from emission units 1, 1A, 1B, 1C, 2, 2A, 2B, 3, 3A, 3B, 3C, 3D, 4, 4A, 4B, 4C, 4D, 4F, 5, 5A, 5B, 5C, 6, 6A, 6B, 6C, 7, 7A, 7B, 8, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 9, 9A, 9B, 10, 10A, 10B, 10C, 11, 11A, 12, 13, 14A-C, 15A-C exceed 58.0 tons per year in any 12-month period, the permittee shall notify the Department in writing within 15 days of the date the calculation was made.

2. **CO Emissions Calculations**: By the 15th day of each month, the owner/operator shall calculate and record the total CO emissions from the following emission units: 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C for the previous month and for the previous 12 months (12-month rolling total). Emissions shall be calculated in a method as shown below.

CO_{Total} = $CO_{HEATERS/BOILERS}$ (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G) + CO_{FLARES} (EUs 10, 10A, 10B, 10C) + $CO_{ENGINES}$ (EUs 14A-C, 15A-C)

Where:

$CO_{HEATERS/BOILERS}$ = Total CO emissions (in tons) from EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, and 8G

$CO_{HEATERS/BOILERS}$ = Total CO emissions calculated via use of the CO CEMS for EUs 1A, 1B, 2A, 4A, 4B, 4C, 6A, and 6B

$CO_{HEATERS/BOILERS}$	=	(Total heat content of refinery gas combusted in EUs 3A, 3B, 3C, 4D, 5A, 5B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, and 8G, million Btu) x (CO burners specification[5] of lb / million Btu heat input) / 2000
$CO_{FLARING}$	=	Total CO emissions (in tons) from EUs 10, 10A, 10B, 10C
$CO_{FLARING-PILOT}$	=	(total heat content of pilot gas combusted in EU 10, 10A, 10B, and 10C, million Btu) x (0.028 lb CO / million Btu heat input) / 2000
$CO_{FLARING-BLOWDOWN}$	=	(Blowdown hours) x (4.3 lb CO / Mbbl Refining Capacity) x (Crude Processing Rate, Mbbl/day) / 24 / 2000
$CO_{ENGINES}$	=	Total CO emissions (in tons) from EUs 14A-C and 15A-C from non-emergency operations
$CO_{ENGINES}$	=	[((hours of operation of EUs 14A-C) x (5.5×10^{-3} lb of CO / hour of operation) x (bhp of EUs 14A-C)) + ((hours of operation of EUs 15A-C) x (5.5×10^{-3} lb of CO / hour of operation) x (bhp of EUs 15A-C))] / 2000

Combined CO emissions from the emission units listed are restricted to 80.0 tons per year. If total calculated combined CO emissions from emission units 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C exceed 80.0 tons per year in any 12-month period, the permittee shall notify the Department in writing within 15 days of the date the calculation was made.

3. **NO_X Emissions Calculations**: By the 15th day of each month, the owner/operator shall calculate and record the total NO_X emissions from the following emission units: 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C for the previous month and for the previous 12 months (12-month rolling total). Emissions shall be calculated in a method as shown below.

$NO_{X-Total}$	=	$NO_{X-HEATERS/BOILERS}$ (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G) + $NO_{X-FLARES}$ (EUs 10, 10A, 10B, 10C) + $NO_{X-ENGINES}$ (EUs 14A-C, 15A-C)

[5] When calculating emissions, the burner specification shall be utilized unless a Department-approved performance test has been conducted to determine CO emissions from the emission unit. After completion of a Department-approved performance test and verification of the results by the Department, the results of the Department-approved performance test shall be used to calculate emissions.

Where:

$NO_{X\text{-HEATERS/BOILERS}}$ = Total NO_X emissions (in tons) from EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, and 8G

$NO_{X\text{-HEATERS/BOILERS}}$ = Total NO_X emissions calculated via use of the NO_X CEMS for EUs 1A, 1B, 2A, 4A, 4B, 4C, 6A, and 6B

$NO_{X\text{-HEATERS/BOILERS}}$ = (Total heat content of refinery gas combusted in EUs 3A, 3B, 3C, 4D, 5A, 5B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, and 8G, million Btu) x (NO_X burners specification[6] of lb / million Btu heat input) / 2000

$NO_{X\text{-FLARING}}$ = Total NO_X emissions (in tons) from EUs 10, 10A, 10B, 10C

$NO_{X\text{-FLARING PILOT}}$ = (total heat content of pilot gas combusted in EU 10, 10A, 10B, and 10C, million Btu) x (0.03 lb NO_X / million Btu heat input) / 2000

$NO_{X\text{-FLARING-BLOWDOWN}}$ = (Blowdown hours) x (19 lb NO_X / Mbbl Refining Capacity) x (Crude Processing Rate, Mbbl/day) / 24 / 2000

$NO_{X\text{-ENGINES}}$ = Total NO_X emissions (in tons) from EUs 14A-C and 15A-C from non-emergency operations

$NO_{X\text{-ENGINES}}$ = [((hours of operation of EUs 14A-C) x (0.013 lb of NO_X / hour of operation) x (bhp of EU14s A-C)) + ((hours of operation of EUs 15A-C) x (0.013 lb of NO_X / hour of operation x (bhp of EU15s A-C)))] / 2000

Combined NO_X emissions from the emission units listed are restricted to 40.0 tons per year. If total calculated combined NO_X emissions from emission units 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C exceed 40.0 tons per year in any 12-month period, the permittee shall notify the Department in writing within 15 days of the date the calculation was made.

4. **SO_2 Emissions Calculations**: By the 15th day of each month, the owner/operator shall

[6] When calculating emissions, the burner specification shall be utilized unless a Department-approved performance test has been conducted to determine NOx emissions from the emission unit. After completion of a Department-approved performance test and verification of the results by the Department, the results of the Department-approved performance test shall be used to calculate emissions.

calculate and record the total SO_2 emissions from the following emission units: 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C for the previous month and for the previous 12 months (12-month rolling total). Emissions shall be calculated in a method as shown below.

$SO_{2\text{-Total}}$ = $SO_{2\text{-HEATERS/BOILERS}}$ (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, 8G) + $SO_{2\text{-FLARES}}$ (EUs 10, 10A, 10B, 10C) + $SO_{2\text{-ENGINES}}$ (EUs 14A-C, 15A-C) + $SO_{2\text{-SRU}}$ (EU 7A)

Where:

$SO_{2\text{-HEATERS/BOILERS}}$	=	Total SO_2 emissions (in tons) from EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, and 8G
$SO_{2\text{-HEATERS/BOILERS}}$	=	(Total hourly refinery gas combusted in EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, and 8G, scf) x (hourly fuel gas H_2S concentration, ppmv) x (1×10^{-6}) x (1 lb mol/379 scf) x (64.06 lb SO_2 / lb mol SO_2) / 2000
$SO_{2\text{-SRU}}$	=	Total SO_2 emissions (in tons) from EU 7A
$SO_{2\text{-SRU}}$	=	Total SO_2 emissions calculated via use of SO_2 CEMS on EU 7A
$SO_{2\text{-FLARING}}$	=	Total SO_2 emissions (in tons) from EUs 10, 10A, 10B, 10C
$SO_{2\text{-FLARING}}$	=	Total SO_2 emissions calculated via use of sulfur monitoring[7]
$SO_{2\text{-ENGINES}}$	=	Total SO_2 emissions (in tons) from EUs 14A-C and 15A-C from non-emergency operations
$SO_{2\text{-ENGINES}}$	=	[((hours of operation of EUs 14A-C) x (4.5×10^{-6} lb of SO_2 / hour of operation) x (bhp of EUs 14A-C)) + ((hours of operation of EUs 15A-C) x (4.5×10^{-6} lb of SO_2 / hour of operation) x (bhp of EUs 15A-C))] / 2000

[7] Derived via use of sulfur monitoring required by NSPS Subpart Ja.

Combined SO_2 emissions from the emission units listed are restricted to 13.0 tons per year. If total calculated combined SO_2 emissions from emission units 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C exceed 13.0 tons per year in any 12-month period, the permittee shall notify the Department in writing within 15 days of the date the calculation was made.

E. **Monitoring Conditions**:

1. Summary Table:

Emission Unit	**EU**	**EP**	**Pollutant/ Parameter**	**Monitoring Requirement**	**Reference Condition II.E.**
ADU process equipment		e	VRU Flow	ELDAR Recordkeeping	12 16
ADU Feed Heater #1 rated heat input of 82.13 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	CEMS CEMS CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	6 7 2 9 9
ADU Feed Heater #2 rated heat input of 82.13 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	CEMS CEMS CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	6 7 2 9 9
ADU sewers		e	VOC	Inspections/Repairs	11
VDU process equipment		e	VRU Flow	ELDAR Recordkeeping	12 16

VDU Feed Heater rated at 75.00 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	CEMS CEMS CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	6 7 2 9 9
VDU sewers		e		Inspections/Repairs	11
NHT process equipment		e	VRU Flow	ELDAR Recordkeeping	12 16
NHT Feed Heater rated 8.60 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	Emissions Test Emissions Test CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	8 8 2 9 9
NHT Stabilizer Reboiler rated 9.30 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	Emissions Test Emissions Test CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	8 8 2 9 9
NHT Splitter Reboiler rated at 17.90 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	Emissions Test Emissions Test CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	8 8 2 9 9
NHT sewers		e		Inspections/Repairs	11
CRU process equipment		e	VRU Flow	ELDAR Recordkeeping	12 16

CRU Reactor #1 Heater rated at 45.63 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	CEMS CEMS CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	6 7 2 9 9
CRU Reactor #2 Heater rated at 45.63 MMbtu/hr					
CRU Reactor #3 Heater rated at 45.63 MMbtu/hr					
CRU Stabilizer Reboiler rated at 5.70 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	Emissions Test/O&M Emissions Test/O&M CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	8 8 2 9 9
CRU Regenerator Vent				Recordkeeping	10
CRU sewers		e		Inspections/Repairs	11
DHT process equipment		e		ELDAR	12
DHT Feed Heater rated at 19.50 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	Emissions Test Emissions Test CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	8 8 2 9 9
DHT Splitter Reboiler rated at 27.30 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	Emissions Test Emissions Test CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	8 8 2 9 9
DHT sewers		e		Inspections/Repairs	11

HYK process equipment		e	VRU Flow	ELDAR Recordkeeping	12 16
HYK Reactor Heater rated at 37.16 MMtbu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	CEMS CEMS CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	6 7 2 9 9
HYK Fractionator Heater rated at 40.34 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	CEMS CEMS CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	6 7 2 9 9
HYK sewers		e		Inspections/Repairs	11
SRU process equipment		e		ELDAR	12
Thermal Oxidizer with a rated capacity of 1.58 MMbtu/hr				CEMS	5
SRU sewers		e		Inspections/Repairs	11
Process equipment		e		ELDAR	12
Medium Pressure Steam Boiler #1 rated at 11.68 MMbtu/hr			CO SO_2 PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	Emissions Test Emissions Test Fuel Records Emissions Test/ Recordkeeping Recordkeeping	8 8 2 9 9
Medium Pressure Steam Boiler #2 rated at 11.68 MMbtu/hr					
Medium Pressure Steam Boiler #3 rated at 11.68 MMbtu/hr					

Medium Pressure Steam Boiler #4 rated at 11.68 MMbtu/hr					
High Pressure Steam Boiler #1 rated at 22.00 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	Emissions Test Emissions Test CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	8 8 2 9 9
High Pressure Steam Boiler #2 rated at 22.00 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	Emissions Test Emissions Test CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	8 8 2 9 9
High Pressure Steam Boiler #3 rated at 22.00 MMbtu/hr			CO H_2S PM_{10} & $PM_{2.5}$ (Filterable + Condensable) Opacity	Emissions Test Emissions Test CMS (H_2S in Fuel Gas) Emissions Test/ Recordkeeping Recordkeeping	8 8 2 9 9
Process equipment		e		ELDAR	12
Storage Tank Farm				Inspections/Repairs	13
Oil Movement sewers		e		Inspections/Repairs	11
Enclosed hydrocarbon (HC) operating flare rated to handle up to 24.4 MMscf/day (including purge and fuel gas blowdown)				Flow monitor / recordkeeping	4

Acid gas flare rated to handle up to 15.8 MMscf/day			H_2S Total Reduced Sulfur (TRS)	Flow monitor / recordkeeping CEMs Calculation based on CEMs monitoring	3
HC secondary flare #1 rated to handle up to 74.6 MMscf/day of emergency relief			Pressure and Liquid Level	Flow monitor / recordkeeping Continuous parameter monitoring system (CPMS)	4
HC secondary flare #2 rated to handle up to 88.8 MMscf/day of emergency relief			Pressure and Liquid Level	Flow monitor / recordkeeping CPMS	4
Process Equipment		e		ELDAR	12
Truck loading rack vent				VRU / ELDAR and monthly Olfactory, Visual and Audible (OVA) observations and product throughput	12 / Condition II.A.13
Oil/Separator inlet from Benzene Waste Operators NESHAP (BWON) compliant plant		e	TAB	ELDAR Recordkeeping	12 17
CT cell #1				Recordkeeping	Condition II.A.15.b
CT cell #2					
CT cell #3					
CT cell #4					
CT cell #5					
Diesel Engine Power Generators rated at 4700 BHP	14B 14C	14B 14C		Maintenance records / hours of operations records	15

Back-up Diesel Engine Firewater Pumps rated at 350 BHP	15B 15C	15B 15C		Maintenance records / hours of operations records	15

2. **Continuous Monitoring System (CMS) – FGCD Hydrogen Sulfide (H_2S) Monitoring for SO_2 Emissions:** For each FGCD subject to an SO_2 or H_2S limit (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8E, 8F, and 8G), the permittee shall comply with the following conditions.

   a. The permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of hydrogen sulfide in the fuel gases before being burned in any fuel gas combustion device. Monitoring of H_2S must also meet all applicable requirements of NSPS Ja, including the applicable requirements of §60.107a(a)(2).

   b. FGCDs having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned in the respective FGCD. The permittee has elected to monitor the H_2S concentration on the RFG system header exiting the SRU that is common to all the FGC units to comply with §60.107a(a)(2)(iv).

3. **CEMS and Continuous Parameter Monitoring System (CPMS) – Acid Gas Flare System (EU 10A) Sulfur, H_2S and Total Reduced Sulfur (TRS) Emissions:**

   a. The presence of a flame shall be monitored using a thermocouple or any other equivalent device approved by the Department.

   b. The permittee shall install, operate, calibrate a continuous parameter monitoring system to measure and record the flow rate of gas discharged to the flare. Flare gas flow monitoring must also meet all applicable requirements of NSPS Ja, including the applicable requirements of §60.107a(f).

   c. The permittee shall comply with the sulfur monitoring requirements in §60.107a(e) for assessing the root cause analysis threshold for the flare.

4. **Continuous Parameter Monitoring – Enclosed HC Flare System (EU 10) and Secondary HC Flares (EU 10B, EU 10C)**: For each flare subject to the NSPS Ja standards, the permittee shall comply with the following conditions:

   a. The presence of a flame shall be monitored using a thermocouple or any other equivalent device approved by the Department.

   b. The permittee shall operate the pilots using exclusively pipeline quality natural gas.

c. The permittee shall install, operate, calibrate a continuous parameter monitoring system to measure and record the flow rate of gas discharged to the flare. Flare gas flow monitoring shall meet all applicable requirements of NSPS Ja, including the applicable requirements of §60.107a(g).

5. **Continuous Emission Monitoring System (CEMS) – SRU Thermal Oxidizer (EP 7A) SO_2 Emissions**: The permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration of SO_2 and O_2 emissions into the atmosphere. Monitoring of SO_2 and O_2 emissions must also meet all applicable requirements of NSPS Ja, including the applicable requirements of §60.106a(a)(1).

6. **CEMS – FGCD Nitrogen Oxide (NO_X) Emissions for EUs 1A, 1B, 2A, 4A, 4B, 4C, 6A, and 6B**: The permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of NO_X emissions into the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air. Monitoring of NO_X emissions must also meet all applicable requirements of NSPS Ja, including the applicable requirements of §60.107a(c).

7. **CEMS – FGCD Carbon Monoxide (CO) Emissions for EUs 1A, 1B, 2A, 4A, 4B, 4C, 6A, and 6B**: The permittee is not required by either State or Federal regulations to install continuous monitor emissions of CO into the atmosphere. However, the permittee has elected to utilize CO CEMS to demonstrate compliance with the facility wide CO emissions restriction under Condition II.D.2. These monitors shall be installed on EU's 1A, 1B, 2A, 4A, 4B, 4C, 6A, and 6B.

8. **Portable Analyzer Testing for EUs 3A, 3B, 3C, 4D, 5A, 5B, 8A, 8B, 8C, 8D, 8E, 8F, and 8G:** Once during the permit period, or when changes are made to a FGCD that may increase emission rates, whichever is more frequent, to provide a reasonable assurance of compliance, the permittee shall conduct an emissions test to measure NO_X and CO emissions, using at a minimum, a portable analyzer with quality assurance procedures equivalent to Conditional Test Methods 22 and/or 30 as outlined in EPA's Emission Measurement Center[8]. A test shall consist of three runs, with each run at least 20 minutes in length.

9. **Fuel Gas - Opacity and Particulate Matter for EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, and 8G**: For purposes of compliance monitoring after the initial emissions test, burning of gaseous fuel shall be considered credible evidence of compliance with any applicable opacity and particulate

[8] CTM-022 and/or CTM-030. https://www.epa.gov/emc/emc-conditional-test-methods

matter emission limit. However, results from tests conducted in accordance with the test methods in 40 CFR 60 will take precedence over burning of gaseous fuel for evidence of compliance or noncompliance with any applicable opacity or particulate limit in the event of enforcement action. The permittee shall record the type of fuel used in the source unit on a daily basis.

10. **CRU Regenerator Vent (EU 4E) - Opacity**: For purposes of compliance monitoring, the inherent design and operation of the process vents shall be considered credible evidence of compliance with the visible emissions standards. However, results from tests conducted in accordance with Method 22 of 40 CFR 60, Appendix A will take precedence for evidence of compliance or noncompliance with an applicable visible emission limit, in the event of enforcement action.

11. **40 CFR 60 Subpart QQQ Monitoring/Inspections for EUs 1C, 2B, 3D, 4F, 5C, 6C, 7B, 9B, and 12**: The permittee shall comply with the performance test methods and procedures and compliance provisions of §60.696(a) – (d), as applicable. Additionally, the following affected facilities are subject to the following requirements:

    a. Individual Drain Systems:

        i. Drains shall comply with the monitoring requirements of §60.692-2(a)(2)-(5).

        ii. Junction boxes shall comply with the monitoring requirements of §60.692-2(b)(3)-(4).

        iii. Sewer Lines shall comply with the monitoring requirements of §60.692-2(c)(2)-(3).

    b. Oily Water Separator: Each OWS shall comply with the monitoring requirements of §60.926-3(a)(3)-(5).

    c. Closed Vent System: Each closed vent system shall comply with the monitoring requirements of §60.692-5(e)(1)-(5).

12. **Enhanced LDAR Monitoring/Inspections/Repairs for EUs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, and 11A:** The permittee shall comply with the provisions of §63.162 - §63.174 and §63.180.

    a. Each pump in light liquid service shall be monitored following the requirements of §63.163(e).

    b. Each compressor shall be monitored following the requirements of §63.164(e)-(h).

c. All pressure relief devices in gas/vapor service shall be monitored following the requirements of §63.165(a) – (d).

d. All sampling connection systems shall be monitored following the requirements of §63.166(a) – (c).

e. All open-ended valves and lines shall be monitored following the requirements of §63.167(a) – (e).

f. All valves in gas/vapor and light liquid service shall meet the requirements of §63.168(b) – (h).

g. Pumps, valves, connectors, and agitators in heavy liquid service; instrument systems; and pressure relief devices in liquid service. All Pumps, valves, connectors, and agitators shall be monitored following the requirements of §63.169(a) – (d).

h. Each surge control vessel and bottoms receiver shall be monitored following the requirements of §63.172(a) – (n).

i. Each closed-vent systems and control devices shall be monitored following the requirements of §63.172(a) – (n).

j. Each agitator in gas/vapor and light liquid service shall be monitored following the requirements of §63.173(a) – (j).

k. Each connector in gas/vapor service and light liquid service shall be monitored following the requirements of §63.174(a) – (h).

13. **VOL Storage Tanks Inspections/Monitoring/Repairs:**

a. For the IFR Tanks (301, 302, 305, 306, 307, 308, 309, 311, 312, 327, 328, 331, and 332), the permittee shall comply with the floating roof inspection, monitoring, and repair requirements of §63.1063(c) – (e).

b. For the FR Tanks (313, 315, 316, 324, and 325) the permittee shall comply with the fixed roof inspection, monitoring, and repair requirements of §63.1063(c) – (e).

14. **40 CFR 60, Subpart Dc for EUs 8A, 8B, 8C, 8D, 8E, 8F, and 8G**: The permittee shall comply with all applicable requirements of 40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

15. **40 CFR 60, Subpart IIII for EUs 14A, 14B, 14C, 15A, 15B and 15C**: The permittee shall comply with all applicable requirements of 40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

16. **40 CFR 60, Subpart NNN for EU 1, 2, 3, 4, 6 and the Benzene Saturation Unit**: The permittee shall operate a properly designed and sized vapor recovery system to collect the vent streams of the affected facilities and comply with the monitoring of emissions and operations provisions of §60.663(b). The permittee shall install, operate, calibrate and maintain a flow indicator to record an instrument for continuously monitoring the vent stream flow from the vapor recovery system to the flare in accordance with §60.662(b).

17. **40 CFR 61, Subpart FF for Waste Water Treatment Plant (EU 12)**: The oily water treatment system and individual drain lines that convey process waste water to the oily water treatment system are subject to the applicable requirements of this subpart. Waste that is contained in a segregated stormwater sewer system and any gaseous stream from a waste management unit, treatment process, or wastewater treatment system routed to a fuel gas system, are exempt from compliance with the provisions of this subpart.

    a. The permittee shall determine the total annual benzene (TAB) quantity from facility waste by the procedures described in §61.355.

    b. If the TAB is greater than 1 Mg/year but less than 10 Mg/year, the permittee will comply with the reporting (§61.357) and recordkeeping requirements (§61.356).

    c. Repeat the determination of the TAB at least once a year or when the process changes can cause the TAB to increase above 10 Mg/yr.

    d. Follow the standards set for tanks, containers, drain systems, oil water separators, and closed vent systems and control devices as required under Subpart FF.

F. **Recordkeeping and Reporting Requirements**: All records and reports shall be available for inspection by Department personnel and shall be submitted to the Department upon request. The following records shall be maintained:

1. All recordkeeping and reporting required by applicable federal standards established under 40 CFR 60 - Standards of Performance for New Stationary Sources. The records shall comply with the applicable requirements of the following subparts:

    a. NSPS A: §60.19.

    b. NSPS Dc: §60.48c.

    c. NSPS Ja: §60.108a.

In addition, for EU 10 Flares, make available 15 days after the end of the month: monthly flow, temperature, and hours of operation.

d. NSPS Kb: §60.115b.

For fixed roof tanks, the permittee shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

e. NSPS GGGa (references NSPS VVa): §60.486a and §60.487a.

f. NSPS NNN: §60.665.

g. NSPS QQQ: §60.697 and §60.698.

h. NSPS IIII: §60.4214.

Annual reporting [§60.4214(d)] of the EU 14A-C Diesel Generator and EU 15A-C Back-up Diesel Engine Fire Pump engine hours not to exceed 100 hours to include reason for operating (§60.4211(f)(2)(i)). The 100 hour of operation limit includes the sum of hour of operation of the engines in non-emergency use, or maintenance and readiness testing. The number of hours operating in an actual emergency do not have a limit.

Annual reporting [§60.4207(b)] of diesel used by EU 14A-C Diesel Generator and EU 15A-C Back-up Diesel Engine Fire Pump.

2. All recordkeeping required by applicable federal standards established under 40 CFR Part 61 – National Emission Standards for Hazardous Air Pollutants.

a. NESHAP FF: §63.356 and §63.357.

Annual calculation of the annual average benzene concentration of waste streams.

3. All recordkeeping required by applicable federal standards established under 40 CFR Part 63 – National Emission Standards for Hazardous Air Pollutants for Source Categories.

a. MACT H: §63.181 and §63.182.

b. MACT WW: §63.1065 and §63.1066.

c. MACT 6B: §63.11094 and §63.11095.

Gasoline Loading Rack ELDAR inspection (500 ppmv).

Gasoline Loading Rack OVA and/or LDAR leak inspection on all equipment in gasoline service (§63.11089).

Gasoline Loading Rack monthly gasoline throughput made available 15 days after the end of the month.

4. Additional Requirements

a. All stack test results including field data, laboratory analysis data, and quality assurance data.

b. Semi-Annual reporting of CEMS observations for all units subject to monitoring.

c. Annual Emission Inventory/Annual Production Reports: The owner/operator shall submit an annual emission inventory report and/or an annual production report upon Department request, on forms supplied or approved by the Department.

The owner/operator shall maintain any compliance monitoring records required by this permit or applicable requirements. The owner/operator shall retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report or application. Support information may include all calibration and maintenance records and all original strip-chart recordings/computer printouts for continuous monitoring instrumentation, and copies of all reports required by the permit.

General Conditions

G. **Construction**: Construction of the above described facility shall be in accordance with information provided in the permit application as well as any plans, specifications and supporting data submitted to the Department. The Department shall be notified ten days in advance of any significant deviations from the specifications furnished. The issuance of this Permit to Construct may be suspended or revoked if the Department determines that a significant deviation from the plans and specifications furnished has been or is to be made.

Any violation of a condition issued as part of this permit to construct as well as any construction which proceeds in variance with any information submitted in the application, is regarded as a violation of construction authority and is subject to enforcement action.

H. **Startup Notice**: A notification of the actual date of initial startup shall be submitted to the Department within 15 days after the date of initial startup.

I. **Organic Compounds Emissions**: The permittee shall comply with all applicable requirements of NDAC 33-15-07 – Control of Organic Compounds Emissions.

J. **Air Pollution from Internal Combustion Engines**: The permittee shall comply with all applicable requirements of NDAC 33-15-08-01 – Internal Combustion Engine Emissions Restricted.

K. **Fugitive Emissions**: The release of fugitive emissions shall comply with the applicable requirements in NDAC 33-15-17.

L. **Title V Permit to Operate**: Within one year after startup of the units covered by this Permit to Construct, the owner/operator shall submit a permit application for a Title V Permit to Operate for the facility.

M. **Permit Invalidation**: This permit shall become invalid if construction is not commenced within eighteen months after issuance of such permit, if construction is discontinued for a period of eighteen months or more; or if construction is not completed within a reasonable time.

N. **Source Operations**: Operations at the installation shall be in accordance with statements, representations, procedures and supporting data contained in the initial application, and any supplemental information or application(s) submitted thereafter. Any operations not listed in this permit are subject to all applicable North Dakota Air Pollution Control Rules.

O. **Alterations, Modifications or Changes**: Any alteration, repairing, expansion, or change in the method of operation of the source which results in the emission of an additional type or greater amount of air contaminants or which results in an increase in the ambient concentration of any air contaminant, must be reviewed and approved by the Department prior to the start of such alteration, repairing, expansion or change in the method of operation.

P. **Nuisance or Danger**: This permit shall in no way authorize the maintenance of a nuisance or a danger to public health or safety.

Q. **Malfunction Notification**: The owner/operator shall notify the Department of any malfunction which can be expected to last longer than twenty-four hours and can cause the emission of air contaminants in violation of applicable rules and regulations.

R. **Operation of Air Pollution Control Equipment**: The owner/operator shall maintain and operate all air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

S. **Transfer of Permit to Construct:** The holder of a permit to construct may not transfer such permit without prior approval from the Department.

T. **Right of Entry**: Any duly authorized officer, employee or agent of the North Dakota Department of Health may enter and inspect any property, premise or place at which the source listed in Item I.B of this permit is located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules. The Department may conduct tests and take samples of air contaminants, fuel, processing material, and other materials which affect or may affect emissions of air contaminants from any source. The Department shall have the right to access and copy any records required by the Department's rules and to inspect monitoring equipment located on the premises.

U. **Other Regulations**: The owner/operator of the source unit(s) described in Item I.B of this permit shall comply with all State and Federal environmental laws and rules. In addition, the owner/operator shall comply with all local burning, fire, zoning, and other applicable ordinances, codes, rules and regulations.

V. **Permit Issuance**: This permit is issued in reliance upon the accuracy and completeness of the information set forth in the application. Notwithstanding the tentative nature of this information, the conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has, or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23-25.

W. **Odor Restrictions**: The owner/operator shall not discharge into the ambient air any objectionable odorous air contaminant which is in excess of the limits established in NDAC 33-15-16.

X. **Sampling and Testing**: The Department may require the owner/operator to conduct tests to determine the emission rate of air contaminants from the source. The Department may observe the testing and may specify testing methods to be used. A signed copy of the test results shall be furnished to the Department within 60 days of the test date. The basis for this condition is NDAC 33-15-01-12 which is hereby incorporated into this permit by reference. To facilitate preparing for and conducting such tests, and to facilitate reporting the test results to the Department, the owner/operator shall follow the procedures and formats in the Department's Emission Testing Guideline.

FOR THE NORTH DAKOTA
DEPARTMENT OF HEALTH

Date______________________ By__________________________________

Terry L. O'Clair, P.E.
Director
Division of Air Quality